ADANI THERMAL, TRANSMISSION & RENEWABLES

Comment on Consultation Paper
Of CERC for determination of
Terms & Conditions of Tariff
for the period commencing from 01.04.2019

CERC Public Notice dated 24.05.2018/13.07.2018

Comments to be submitted by 31.07.2018

Comments on Consultation paper

- Regulatory Certainty - Tariff Policy mandates regulatory certainty. Power sector is going through tough period and is not in any position to own risk of unknown. Therefore, any changes to the existing provisions of the Regulations should be made only if there is difficulties in implementing the same. Any radical change introduced which endangers and attempts to reduce the existing Fixed Cost or tariff receivable by Generating Company or Licensee will increase the risk perception of the said projects in the eyes of lenders and credit rating agencies. On account of higher risk perception, it will lead to a higher interest rate to be charged by the lenders which will then be passed on to beneficiaries since interest on normative loan is equivalent to normative loan X actual weighted average rate of interest on loan portfolio. Thus any radical change to reduce the tariff of Generating Companies/Licensees may backfire and may not lead to desired results and may prove to be detrimental to the interest of consumers as it will increase the Tariff

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1.	7.2.4	The possible options for tariff structure could be to offer to the procurers having low demand a menu of options for ensuring dispatch by linking a portion of fixed charges with the actual dispatch and balance of AFC to availability. This will ensure optimum utilization of the infrastructure, as procurers will continue to procure power from the generating stations and the generator will get reasonable return without losing the demand	✓ Three Part Tariff is not in consonance with the Tariff Policy/ proposed amendments in Tariff Policy which mandates Two part tariff for thermal project. ✓ It is not explained as to how three part tariff will improve PLF of thermal plants. PLF is function of the demand. Unless demand is increased globally, PLF may not improve. One of the reasons for low PLF is non-cost-effective retail tariff approved by the SERCs. As a result, distribution utilities prefer to load shedding instead of procuring power from generators that are high in MoD. ✓ Reason considered as a base for such proposal that there is power surplus situation. The same needs review. Recently, short term power purchase rate (which is indicator of requirement/demand) in Exchange had soared to Rs 5-6 per kwh. Also, during FY 17-18, short term bids aggregating more than 30000 MW is issued by different states and the rate therein is also in this range. The quantum has also increased. Therefore, the proposal at this stage is premature. ✓ Recently, MSEDCL has sought permission of MERC above ceiling rate of Rs 4 per kWh fixed for short term power purchase in view of the
2.	7.2.5	The tariff for supply of electricity from a thermal generating station could comprise of three parts, namely, fixed charge (for recovery of fixed cost consisting of the components of debt service obligations allowing depreciation for repayment, interest on loan and guaranteed return to the extent of risk free return and part of operation and maintenance expenses), variable charge (incremental return above guaranteed return and balance operation and maintenance expenses) and energy charges (fuel	

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		cost, transportation cost and taxes, duties of fuel).	rates discovered in its recent tenders mainly between 4.50 per kWh to 6.29 per kWh. ✓ As per the details available in CEA periodic reports, it is observed that monthly PLF for last 5 months in current calendar year is higher as compared to corresponding figure in last Calendar Year. ✓ Therefore, Low PLF as envisaged in the Approach Paper is not a proven situation and expecting it to continue throughout the next tariff period of 2019-24 may prove to be a fallacious assumption in hindsight in 2024. There are multiple reports of various consultants and expert bodies which expect the PLF in coming years to rise. ✓ Further it is not known whether the Low PLF is on account of low demand or on account of all customers not being serviced. There are still portions of the country which are not electrified / which do not have 24 X 7 Reliable Power Supply. Also, the outages are being undertaken by Discoms due to high AT&C losses which may be contributing to low PLF. The sovereign objective to supply power 24x7 cannot go hand in hand with situation of low PLF. ✓ Per capita consumption of India has increased has almost doubled in FY 2017 (1122 kwh) as compared to that in FY 2002 (559 kwh).Still it is only 1/3rd of the world's average per capita with highest per capita of about 15000 kwh for Canada and USA. The government of India is committed to increase the per capita. Under the circumstance, one cannot anticipate low PLF situation or provide solution to such a temporary phenomenon, even if it is. ✓ GOI is trying to address the problem by introducing penalties and having Standard of Performance introduced in the amendment to Tariff Policy which shall penalize the Discoms for not ensuring 24X7 supply. With GOI's impetus on improvement in supply of electricity throughout the country, the so assumed low PLF's are bound to increase in the coming tariff period ✓ Further, Projects are evaluated and decisions related to funding are taken based on norms prevailing at the time of project inception. Therefore, Regulatory certainty is the foremost objective for
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4.	7.2.6	The recovery of fixed component could be linked to target availability, whereas variable component could be linked to the difference between availability and dispatch. Fuel charges could be linked with dispatch.	

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			investment. Changing basis in entirety will leave investors with no clue and no investor will put the money in the power sector. ✓ Generators have made huge investments in the Power stations considering two part tariff and recovery of their fixed cost on the basis of declaration upto target availability. Sudden change in this provision, will leave generators with non-recovery of their total fixed cost and will be totally unjustified since demand of power is not within control of Thermal Generator. ✓ Lenders have been providing funds to power projects, considering recovery of total fixed on declaration upto to target availability. This proposed change in regulation by CERC will force the lenders to assign higher risk value to these assets, thus increasing the rate of interest. This high rate of interest will be passed on to the consumers which will increase the tariff. ✓ Issue of low PLF is already addressed by way of amendment in IEGC. ✓ Demand for power is not within control of Thermal Generator. The proposal of Three Part Tariff affects adversely interest of generator for factors beyond his control. As rightly pointed out in Table 6 of the consultation paper, Fixed charge per unit has reduced by 21% in last 8 Years. Further, reduction in the recovery for fixed cost may lead to issue of sustainability. ✓ O&M Expenses is essentially fixed cost and does not have any evident relationship with PLF. Therefore, there is no point in considering part O&M expense under Variable Charge. As per the proposal, almost 80% of the fixed charge will remain to be fixed charge and only 20% will convert into Variable Charge. This coupled with complexity of the proposed mechanism will not yield any effective result. ✓ Further apart from being difficult to implement, three part tariff may not necessarily improve PLF of thermal plant as anticipated. ✓ Apart from above, there is contradiction in the proposal as captured at Para 7.2.4 and Para 7.2.6. The former talks about Variable charge

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			recovery based on availability whereas the later talks about recovery based on difference between availability and dispatch. Similar contradiction exists for recovery of Fixed charge as well. ✓ In view of above, it is proposed to continue with two part tariff and not shift to three part tariff as suggested. ✓ Modality to recover Variable charge is not clear to comment.
5.	7.3.4	A clear policy/ regulatory decision are required in view of a number of thermal stations crossing the age of 25 years. Possible options could be (i) replacement of inefficient sub critical units by super critical units, (ii) phasing out of the old plants, (iii) renovation of old plants or (iv) extension of useful life etc. It is worth to note that performance of a unit does not necessarily deteriorate much with age, if proper O&M practices are followed	✓ While deciding to phase out any sub-critical unit with Super-Critical unit, thorough study need to be carried for cost efficiency. Some of the old plants may be comparably efficient and therefore, before arriving at the decision to phase out old plants, overall cost benefit analysis should be carried out. However out of the 4 options, the decision here has to be on case to case basis. ✓ One such parameter for phasing out old units could be Station Heat Rate. Stations with higher SHR could be phased out.
6.	7.5.4	Transmission tariff can be on two-part basis, wherein the first part can be linked with the access service and second part can be linked with the transmission service.	✓ Electricity Act 2003 mandates the Commissions to determine, inter-alia, tariff for transmission of electricity. The Act does not give power to Commission to specify charges for accessing the transmission system. Any change incorporating access charges would be ulta-virus of the Act. ✓ In case, Two Part tariff is introduced for recovery of Transmission Tariff, either the Transmission Licensees shall be left with under recovery of their cost or some of the beneficiaries will end up paying more than their legitimate share. Example – Assume 2 x 500 MW customers seeking open access. Customer A is using the network for 20% energy transection whereas Customer B for 80%. In this case, both will pay equal access charge but Customer B will bear more service charges even though there is no additional expenditure on this account. ✓ The Two Part Tariff structure is very complex and will be difficult to implement
7.	7.5.5 (a)	The fixed components may consist of either (i) annual fixed cost of some of fixed transmission system designated for access and immediate evacuation, (ii) annual fixed cost of the evacuation transmission system or (iii) part of annual fixed cost of the entire transmission system consisting of debt service obligations, interest on loan, guaranteed return;	
8.	7.5.5 (b)	The variable components may consist of either (i) common transmission system or system strengthening scheme excluding immediate	

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		evacuation transmission system, (ii) common transmission system excluding evacuation transmission system or (iii) sum of incremental return above guaranteed return, operation and maintenance expenses and interest on working capital.	✓ Such change will adversely affect financials of Transmission Licensees, as lenders will consider such change in methodology of recovery of transmission charges as increase in risk perception, leading to higher rate of interest which will lead ultimately lead to higher interest on normative Loan and thus will increase the AFC ✓ Introduction of Two Part Tariff for Transmission Tariff will require amendment / Change in PoC regulation / methodology. ✓ The Transmission Licensee is responsible for maintenance of his line and makes it available for use, while System Operator i.e. RLDC / SLDC, CTU / STU and Laws of Physics decide use of particular transmission line and its loading. The transmission licensee owning a line has no control over use / non- use of his line and hence it is not justifiable to decide tariff based on usage of the line. ✓ Further the system is designed in a manner that there is n-1 contingency hence full capacity of transmission system will never be utilized and hence the Two Part Tariff will lead to under-recovery of Tariff for Transmission Licensee.. ✓ The Electricity Act, 2003 provides for recovery of transmission tariff for use of transmission line, while it is suggested that first part can be linked with access service, which is not recognised by the Act itself and hence, will be ultra vires.
9.	7.5.6	The recovery of fixed component can be linked to the extent of access (Transmission Access Charge) and variable component can be linked to the extent of use, to be recovered in proportion to the power flow (Transmission Service Charge). The fixed component may be linked to evacuation system or on normative basis based on aggregate transmission charges of the identified transmission system under the contract. The variable component may be linked with yearly transmission charges based on actual flow or actual dispatch against long term access.	
10.	7.6.1 (b)	*"For merit order operation, the entire tariff of the renewable generation (which is of the nature of fixed cost) is to be compared with the marginal cost of the other generation (excluding the fixed cost component)."*	✓ Currently Renewable power plant has been granted "Must Run" Status. Developers have set up the plants under long term fixed single part tariff. ✓ Merit Order Dispatch (MoD) if made applicable on the renewable plants, projects set up under the single part Tariff PPA model, needs to be kept out of the same as they were promised a "Must Run Status" and any variation to that will impact their viability. ✓ With regard to applicability of MoD on **future** renewable plants set

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			up in **<u>Two part Tariff</u>** following is proposed: ✓ Fixed Cost Part is excluded as done for any generation source, as that represents Debt interest, depreciation and equity return. These costs don't change whether the plant produces or not. Even the O&M cost in shorter run is incurred by the Solar/Wind plant even if power is not dispatched. ✓ **<u>Thus for MoD can be made applicable only for future renewable plants which are having two part tariff and only the variable part tariff (representing O&M Cost) at best should be compared to the marginal cost of other sources of power.</u>**
11.	7.6.3	Options for Regulatory framework "*There can be Two part tariff structure for renewable generation covered under Section 62 of the Act, which comprises fixed component (debt service obligations and depreciation) and <u>variable component (equal to marginal cost i.e O&M expenses and return on equity</u>) - fixed component as feed-in-tariff (FIT) and variable component equal to capacity augmentation such as storage or back up supply tariff.*"	✓ Stand of commission in treatment of "Return on Equity"("RoE") cannot be different for different sources of energy. RoE is considered as part of Fixed tariff in case of Thermal, Hydro and Transmission. However for Renewable, commission has proposed RoE as part of variable component tariff. It will completely discourage any investment interest as no return would come to equity investors in case of no offtake by the procurer (for no fault of the generator). ✓ It is proposed to consider RoE as part of fixed cost tariff instead of variable cost tariff part.. ✓ Also Renewables by definition covers wide range of Generating plants like Solar, Wind, Biomass, Bagasse, Small Hydro etc which by nature have varying fixed & variable cost of per unit generation. ✓ It is proposed to have separate terms and condition for calculating Fixed and variable cost for all the renewable sources along with cost of battery storage and hybrid plants (Wind + Solar + Battery storage)
12.	8.4	Possible option could be to develop for incentive and disincentive mechanism for different levels of dispatch and specifying the target dispatch expanding	✓ Development of incentive and disincentive mechanism for different levels of dispatch need not be part of Regulation. ✓ The option for development of Incentive and disincentive can be a

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		the scope of Regulation 48 above.	bilateral arrangement. ✓ The Said option would be contradictory since on one hand as per present Tariff Regulations, incentive is offered at higher PLF beyond Normative Availability and on the other hand there will be incentive/disincentive below target availability also.
13.	9.0	Components of Tariff 9.1 Unlike the Central Generating Stations, for privately owned generating stations, not all the generating capacity may have tied up power purchase agreements. In such case, part capacity may have been tied up under Section 63 and/or Section 62 of the Act and balance may have remained as merchant capacity. 9.2 Section 62 of the Act provides that the Appropriate Commission shall determine the tariff for (a) supply of electricity by a generating company to a distribution Licensee, (b) transmission of electricity, (c) wheeling of electricity and (d) retail sale of electricity. Section 61(b) of the Act provides that the Appropriate Commission shall specify the terms and conditions of tariff for generation, transmission, distribution and supply of electricity are conducted on commercial principles. The commercial principles inter-alia emphasize the risk allocation through contractual arrangement such as power purchase agreement in case of generation and transmission service agreement or long term access agreement in case of transmission service. **Options for Regulatory Framework** 9.3 The question is whether the annual fixed charges and energy charges are to be determined to the extent	✓ It is suggested that appropriate regulatory commission should determine tariff for the power station / unit wise as a whole irrespective of the quantum of power contracted under Section 62 to the Discom and then, this tariff can be applied to portion of power contracted under Section 62 while for the balance, tariff discovered through competitive bidding can apply. This is akin to the procedure being followed now by Regulatory Commissions.

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		of the capacity tied up under Section 62 of the Act or for the entire capacity. One approach could be to determine the tariff of the generating station for entire capacity and restrict the tariff for recovery to the extent of power purchase agreement on pro-rata basis and balance capacity will be merchant capacity or tied up under Section 63, as the case may be.	
14.	Optimum utilization of Capacity : Coal based Thermal Generation 10.3	Options for Regulatory Framework (a) Flexibility may be provided to the generating company and the distribution licensee to redefine the Annual Contracted Capacity (ACC) on yearly basis out of total Contracted Capacity (CC), which may be based on the anticipated reduction of utilization. Annual Contracted Capacity (ACC) may be treated as guaranteed contracted capacity during the year for the generating company and the distribution licensee and the capacity beyond the ACC may be treated as Unutilized Capacity (UC). The distribution licensee will have a right to recall Unutilized Capacity during next year and for securing such rights, some part of fixed cost, say 10-20% or to the extent of debt service obligations, may be paid; (b) Such unutilized Capacity may be aggregated and bidded out to discover the market price of surplus capacity. The surplus capacity may be reallocated to the distribution licensee at market discovered price.	✓ Fixed Charges obligation should be with Discoms only. ✓ For optimum Utilisation of Capacity, suitable mechanism can be developed similar to concluded PPAs executed as per Competitive Bidding Guidelines under section 63.
15.	Optimum utilization of Capacity :	Extend the useful life of the project up to 50 years from existing 35 years and the loan repayment period up to 18-20 years from existing 10-12 years for moderating upfront loading of the tariff.	✓ This should not be applicable for existing projects as investment in these assets have been made based on prevalent depreciation rates and any change in the same would affect their finances considerably and lead to higher risk rating which will in turn lead to higher interest rate. The gains accruing to the beneficiaries by reduced depreciation on account of increase in useful life will be offset by

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	Hydro Generation 10.5 (a)		higher interest rate. ✓ Further there is lack of clarity about the treatment to expenses made towards R&M, before the defined life.
16.	Optimum utilization of Capacity: Hydro Generation 10.5 (b)	Assign responsibility of operation of the hydro power stations and pumped mode operations at regional level with the primary objective for balancing. For this purpose, the scheduling of the hydro power operation (generation and pumped mode operation) may have to be delinked from the requirements of designated beneficiaries with whom agreement exists. The power scheduled to the hydro generation can be dispatched to designated beneficiaries through banking facility so that flexibility in scheduling can be achieved for balancing purpose and to 'address the difficulties of cascade hydro power station. Some part of fixed charge liability to the extent of 10-20% against the use of flexible operation and pumped operations may be apportioned to the regional beneficiaries as reliability charges.	✓ It requires more deliberation with a clear process of implementation mechanism.
17.	Optimum utilization of Capacity: Gas based Thermal Generations 10.7	Scheduling and dispatch of gas based generating station may be shifted to regional level with the primary objective of balancing. After meeting the requirement of designated beneficiaries, the regional level system operator can use it for balancing power at the rate specified by the generating companies. Alternatively, all the gas based generating station capacities may be pooled at regional level. After meeting the requirement of designated beneficiaries, the balance generation may be offered for balancing purpose as and when required.	✓ At present cost of Gas Based Thermal Generation is prohibitively high. And hence such generating stations do not get despatch schedule in view of Merit Order Despatch followed. Pooling of such generation at regional level to balance requirement will burden the discoms, which have already contracted for peak requirement.

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18.	11.0	Benchmarking of Capital cost	✓ Given the difference in various technologies and geographical differences leading to different designs and equipment including varying land and transmission cost, it is proposed that no Benchmark Capital Cost is notified for Wind and Solar Projects any longer.
19.	Capital Cost (Thermal & Hydro Generating Stations) 11.6	There are specific issues and challenges in respect of thermal generating stations. i) The claims of deferred works were allowed to be capitalised up to the cut-off date under the head "works deferred for execution/deferred works" but there is no provision for allowing such expenses after cut-off date. In some of the cases, expenditure was allowed even after cut-off date;	✓ There should not be any cut-off date for essential expenses. If there is prudent reasoning for any work be it originally envisaged or other-wise at any time during the tenure of the project, there is no reason to deny the same. ✓ The Commission may include provision related to additional capital expenditure to meet exigency without approaching the Hon'ble Commission beforehand. The Commission may define broad heads in this regard. ✓ Control systems, system softwares etc. are prone to obsolescence due to rapid technological advancement and the same needs to be suitably allowed under additional capital expenditure.
20.	Capital Cost (Thermal & Hydro Generating Stations) 11.9	11.8 One of the options is to move away from investment approval as reference cost and shift to benchmark/reference cost for prudence check of capital cost. However, the challenge is absence of credible benchmarking of technology and capital cost. 11.9 Higher capital cost allows the developer return on higher base of equity deployed. In the cost plus pricing regime, the developer envisages return on equity as per the original project cost estimation. The regulations allow compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred. Therefore, in new projects, the fixed rate of return may be restricted to the base corresponding to the normative equity as envisaged in the investment approval or on benchmark cost. The return on additional equity may be restricted	✓ No. of variable factors in a generation plant or in transmission lines are so high that each plant is unique in itself, as far as design and investment is concerned and therefore, it is practically impossible to define the benchmark cost. ✓ There is no regulatory sanctity for Benchmarking Norms or Investment Approval. The Commission has dispensed off with the requirement of prior capital cost approval also. ✓ Once prudence check has been performed and only legitimate costs are allowed, then such costs alongwith the costs related to its financing plan are to be also allowed. ✓ For increase in capital cost due to uncontrollable factors, developer will have to incur the equity which otherwise would have earned the same return / higher return of equity from investment in other businesses (Cost of Equity). ✓ It is to be appreciated that cost over-runs are not completely funded by debt. Proportionate equity has to be brought in by the Promoter. Equity has an opportunity cost. However this cost does not get

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		to the extent of weighted average of interest rate of loan portfolio or rate of risk free return. Further, incentive for early completion and disincentive for slippage from scheduled commissioning can also be introduced.	recorded in books of accounts. Though the Regulation allows compensation towards increase in cost due to uncontrollable factor so as to place the developer to the same economic position had this uncontrollable event not occurred but it is not clear that cost of equity (which is a universal concept) will be allowed as compensation also since it is not recorded in books of accounts and whatever is not recorded in the books of account will not be certified by Auditors and whatever is not certified by auditors might create dispute. ✓ On the other hand, if the increase is due to controllable factors, then the Commission does not allow such capital cost at all. Therefore, there is no point in restricting Return on additional equity to weighted average loan portfolio.
21.	12.4	The old transmission lines and substations are sometimes inadequate to cater to the new demand due to capacity degradation and obsolesce of technology. However, construction of new transmission lines and sub-stations require high initial capital investment and substantial time towards seeking approvals, tackling right of way (ROW) issues and environmental clearances. R&M with and without up-gradation of existing projects is one of the cost effective alternatives to increase the power transmission capabilities. The upgradation of transmission line and substation to higher voltages has emerged as a viable alternative to cater to the load growth or transmission requirements. It also offers commercial advantages as some of the original foundations, structure, or equipment can be re-used with minimal modifications.	✓ The Up-gradation of transmission lines to higher voltages renders the existing foundations, structures and useless because the existing foundation, structures have been built for a particular tensile load. With increase in voltage the re-usage of existing foundations, structures is not possible
22.	12.5	In coastal areas, line structures/ towers, hardwares, conductors etc. get rusted due to saline atmosphere. Lines passing through chemical zones also require to be strengthened by stub strengthening, replacement	✓ Thermal power stations located near coastal areas are also subjected to rusting and require strengthening as well as suitable replacements. Hence similar R&M provision may be included for coastal plants as well.

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		of conductors, hardwares, insulators, earthwire etc. The transmission lines which are in service for more than 25 years are affected due to atmospheric conditions and aging.	
23.	Renovation & Modernisation 12.6	The R&M of transmission system could include Residual Life Assessment of Sub-Station and Transmission Lines, Upgradation of sub-station and transmission line, System Improvement Scheme (SIS) and replacement of equipment. The Commission may allow Renovation & Modernisation (R&M) for the purpose of extension of life beyond the useful life of transmission assets. Alternatively, the Commission may allow special allowance for R&M of transmission assets. Such provision will enable the transmission companies to meet the required expenses including R&M on completion of 25/35 years of useful life of sub-station/transmission line without any need for seeking resetting of capital base.	✓ Depreciation on additional capex should be allowed to commensurate with the residual life of the assets. ✓ At the end of useful life of the assets, beneficiaries should be obligated to pay for the residual value.
24.	Financial Parameters 13.1	The performance based cost of service approach; a combination of actual cost and normative parameters has been evolved for the Tariff regulations. Components like return on equity, operation & maintenance expenses and interest on working capital have been specified on normative basis whereas cost of debt has been allowed based on actual rate of interest on normative debt. The normative parameters are expected to induce operational and financial efficiency. While continuing with the hybrid approach, more weightage may be provided for normative parameters to induce greater efficiency during operation as well as in development phase.	✓ At present Interest on Loan as a component of tariff = Average Normative Debt X Weighted Average Interest Rate of Actual Portfolio ✓ It is suggested to continue with existing methodology of cost of debt being allowed on actual basis on normative debt, since different Generators/Licensees get loans at different rates which is not entirely in their control. PSUs like NTPC/PGCIL get loans at Cheaper rates because of Sovereign Ownership and Implicit Guarantee whereas Private Sector Players get loans at a comparatively higher rate. Now if normative interest rate is fixed PSU's will tend to gain and private sector entities will tend to lose. To create a level playing field it is essential that existing formula may be retained.
25.	Depreciation	a) Increase the useful life of well-maintained plants for the purpose of determination of depreciation for tariff;	✓ Depreciation allowed under the regulatory mechanism is a major component of tariff and assures the cash flow for the project.

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	14.6	b) Continue the present approach of weighted average useful life in case of combination, due to gradual commissioning of units; c) Consider additional expenditure during the end of life with or without reassessment of useful life. Admissibility of additional expenditure after renovation and modernization (or special allowance) to be restricted to limited items/equipment; d) Reassess life at the start of every tariff period or every additional capital expenditure through a provision in the same way as is prescribed in Ind AS and corresponding treatment of depreciation thereof; e) Extend useful life of the transmission assets and hydro station to 50 years and that of thermal (coal) assets to 35 years and bring in corresponding changes in treatment of depreciation. f) Reduce rates which will act as a ceiling. g) Continue with the existing policy of charging depreciation. However, the Tariff Policy allows developer to opt for lower depreciation rate subject to ceiling limit as set by notified Regulation which causes difficulty in setting floor rate, including zero rate as depreciation in some of the year(s).	Frequent revision in depreciation will result in uncertain cash flows and this will create problem in arranging finance for the project. Therefore, it may not be desirable to reassess life and recomputed depreciation at start of every tariff period. ✓ In fact, with more RE sources coming into Grid, useful life of thermal power stations get affected due to frequent cyclic loading, which induces fatigue. Further, frequent shutdowns due to RSD and low PLF will also affect the useful life of the plant which may not be even 25 years. Hence the depreciation shall be maintained for 12 years ✓ Ideally, option g seems the best, as it tends to protect the interest of the existing stakeholders however the residual value/scrap value may be changed to 5% instead of 10% in line with Companies Act, 2013. ✓ Alternatively, depreciation may be linked to debt repayment rather than linking it to useful life of the asset since, loan tenure in most cases is such that a depreciation of 7-8% is needed to repay the loan ever year. Therefore, it is suggested to reassess the depreciation rate which need be enhanced and the salvage value to be considered at 5%. In consonance with Companies Act, 2013 ✓ Depreciation on additional capex should be allowed to commensurate with the residual life of the assets. ✓ At the end of useful life of the assets, beneficiaries should be obligated to pay for the residual value.
26.	Gross Fixed Asset (GFA) Approach 15.2	An option could be to base the returns on the modified gross fixed assets arrived at by reducing the balance depreciation after repayment of loan in respect of original project cost.	✓ To continue approach of RoE till the supply/service continue since: o Unlike debt, developer does not earn return on equity during construction period. o Power Sector is going through critical phase and private investment has died down in generation and transmission projects. Also, existing projects, when conceptualized, were evaluated considering RoE till the supply/service continues.

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			✓ Tariff Policy mandates regulatory certainty and any such move will demotivate the prospective investors. ✓ During the past Tariff Regulations, the returns on modified GFA arrived at by reducing depreciation has not been used after elaborate discussion (ROE versus ROCE approach). ✓ Accordingly this proposal may be disregarded since all past implemented projects achieved financial closure assuming returns on GFA basis and not modified GFA. Tinkering with the methodology will increase the perceived risk and banks will charge a higher interest rate which will be passed on to beneficiaries and thereby negating the gains achieved by basing the returns on modified Gross Fixed Assets.
27.	Debt:Equity Ratio 16.4	For future investments, modify the normative debt-equity ratio of 80:20 in respect of new plants, where financial closure is yet to be achieved.	✓ Most of the projects may not be able to service the debt as the DSCR may fall below the guidelines established by the FIs, if debt: equity ratio of 80:20 is implemented. ✓ Tariff Policy mandate debt: equity ratio of 70:30 ✓ Norms for lending have become stringent after recent scandals and banks have lowered the Loan to Value ratio and are asking for higher equity contribution (skin in the game) hence 70:30 ratio may be retained
28.	Rate of Return on Equity 18.7	(a) Review the rate of return on equity considering the present market expectations and risk perception of power sector for new projects; (b) Have different rates of return for generation and transmission sector and within the generation and transmission segment, have different rates of return for existing and new projects; (c) Have different rates of return for thermal and hydro projects with additional incentives to storage based hydro generating projects; (d) In respect of Hydro sector, as it experiences	✓ There should not be any alteration in the ROE Rate of the existing projects, as investments have been made considering the existing regulations. ✓ Recently, RBI has forecasted inflationary trend and increased Repo Rate from 6% to 6.25%. Private investment is at the lowest level in last decade. G-Sec Rate Curves have hardened ✓ Issue of increased risk on account of land acquisition, RoW issues, R&R has not been captured in the consultation paper which has bearing on the rate. ✓ Further, norms specified by CERC for transmission are to be adopted by SERCs for Distribution also, where it is not possible to bifurcate

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		geological surprises leading to delays, the rate of return can be bifurcated into two parts. The first component can be assured whereas the second component is linked to timely completion of the project; (e) Continue with pre-tax return on equity or switch to post tax Return on equity; (f) Have differential additional return on equity for different unit size for generating station, different line length in case of the transmission system and different size of substation; (g) Reduction of return on equity in case of delay of the project;	New and old assets for working out GFA and hence, it is suggested not to revise RoE even for new Assets; hence it is not advisable to have different ROE Rates for new and existing projects. ✓ Having differential rates of ROE for Generation and Transmission Projects will send a signal that one is more riskier than the other. The same is not true as the risks in a project is dependent on the phase in which the project is in. For example the risks in construction stage for a Transmission Project is much higher on account of obtaining Forest Clearance, ROW etc for the transmission line length as compared to the generation projects which are built within the boundary walls of patch of land whereas the risks in case of operation stage for generation projects is much higher than Transmission Projects since there is fuel risk etc which Transmission Projects do not have to bear. If there was a practise of allowing ROE in pre-COD phase as well as post COD phase then differential ROEs could have been provided, however since the Regulatory practise is only to provide ROE for post COD phase hence rate of RoE (which is posr CoD only) has to essentially reflect the risk taken during construction and not only risk after CoD.
29.	Cost of Debt 19.5	(a) Continue with existing approach of allowing cost of debt based on actual weighted average rate of interest and normative loan, or to switch to normative cost of debt and differential cost of debt for the new transmission and generation projects; b) Review of the existing incentives for restructuring or refinancing of debt; c) Link reasonableness of cost of debt with reference to certain benchmark viz. RBI policy repo rate or 10 year Government Bond yield and have frequency of resetting normative cost of debt;	✓ Looking at current market scenario, lenders are reluctant to lend money ✓ Norms for lending have become stringent after recent scandals ✓ RBI has shown inflationary trend and increased Repo Rate from 6% to 6.25%. Private investment is at the lowest level in last decade ✓ Therefore, existing incentive structure for restructuring may be made more lucrative for generator/ transmission licensee to induce more efforts by considering Actual cost of debt at the start of control period as Normative debt and any saving /loss due to restructuring may be considered on account of Generator/ Licensee during entire control period.
30.	Interest on Working	20.3(a) Assuming that internal resources will not be available for meeting working capital requirement and short-term funding has to be obtained from banking	✓ Due to recent fraud involving LOU, RBI has abolished the concept of LOU and the concept of LC discounting etc. has also taken a beat. Hence the assumption of IWC based on cash credit is appropriate

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	Capital (IOWC)	institutions for working capital, whose interest liability has to be borne by the regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made. (a) Assuming that internal resources will not be available … regulated entity, IWC based on the cash credit was followed during previous tariff period. Same approach can be followed or change can be made. … (e) In view of increasing renewable penetration and continued low demand, the plant load factor of thermal generating stations is expected to be low. As per the present regulatory framework, the normative working capital has been provided considering target availability. In case of wide variation between the plant load factor and the plant availability factor, the normative approach of linking working capital with "target availability" can be reviewed.	and should be retained. ✓ Due to factors such as increase in CPI/ WPI, rupee depreciation, high cost of fuel, bank scandals, fiscal slippage and current account deficit etc. there is bound to be increase in rate of WC. Therefore, the norms needs to be revised upside by increasing margin over base rate from 350 basis point to 500 basis point
31.	Operation and Maintenance (O&M) expenses 21.7	Operation and Maintenance (O&M) expenses (a) Review the escalation factor for determining O&M cost based on WPI & CPI indexation as they do not capture unexpected expenditure; (b) Address the impact of installation of pollution control system and mandatory use of treated sewage water by thermal plant on O&M cost. (c) Review of O&M cost based on the percentage of Capital Expenditure (CC) for new hydro projects; (d) Review of O&M expenses of plants being operated	✓ Base O&M norms for the control period 2019-24 should be fixed by escalating the O&M norms applicable for FY 2013-14 considering the Composite inflation on the basis of WPI & CPI data ✓ Additional O&M expenses to be provided for the environmental protection equipment ✓ Additional O&M expenses is to be provided or imported coal based power plants towards coal jetty, desalination plant etc. Additional O&M expense may be considered for plants located in coastal areas considering impact of corrosion and dredging. ✓ Regulations should have provisions for allowing such unexpected expenditure on case to case basis in addition to WPI and CPI

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		continuously at low level (e.g. gas, Naptha and R-LNG based plants). (e) Rationalization of O&M expenses in case of the addition of components like the bays or transformer or transmission lines of transmission system and review of the multiplying factor in case of addition of units in existing stations; (f) Have separate norms for O&M expenses on the basis of vintage of generating station and the transmission system. (g) Treatment of income from other business (e.g. telecom business) while arriving at the O&M cost.	Indexation ✓ At present, there are no rates defined for O&M of transformers and reactor bays. Separate O&M norms for these assets should also be defined. ✓ Norms fixed for O&M Expenses predominantly reflects expenditure by NTPC/PGCIL having scale of economy with number of avenue to optimize the expenditure unlike small private players. ✓ Tariff Policy mandates that O&M Expenses shall be “Capable of achievement”. Therefore, there cannot be stretched targets which are not possible to achieve. ✓ Also, PGCIL has been charging higher O&M expense for assets of other licensees/ generating companies situated in its premises. ✓ Current Norms for O&M Expense does not take into account RSD. As pointed out in the consultation paper, due to low PLF on account of various reasons, incidence of RSD is expected to increase in future. Higher incidence of RSD results in higher O&M expense due chemical consumption for wet preservation of the boiler, circulation of DM water to restrict oxidation and corrosion in the Boilers etc. It will also result in higher wear and tear and reduced life cycle span. ✓ Therefore, separate norms may be prescribed for private players.
32.	Fuel – Gross Calorific Value (GCV) 22.8	Fuel – Gross Calorific Value (GCV) (a) Take actual GCV and quantity at the generating station end and add normative transportation losses for GCV and quantity for each mode of transport and distance between the mine and plant for payment purpose by the generating companies. In other words, specify normative GCV loss between “As Billed” and “As Received” at the generating station end and identify losses to be booked to Coal supplier or Railways. b) Similarly, specify normative GCV loss between “As	✓ Generator does not have any control on the GCV loss between “As Billed” and “As Received” basis. Hence, it does not make sense to specify normative GCV loss between “As Billed” and “As Received” basis. ~~It would be appropriate to take the actual GCV as received at power station.~~ ✓ Since Grade slippage is not attributable to Generating Company, there will be under recovery, if not allowed. Therefore, GCV used for calculation of Energy charge should be on “As fired” basis. Alternatively GCV ~~(~~“As received ~~GCV~~ at plant end ~~+~~ - actual stacking loss~~)~~ may be considered. ~~, as these are the most realistic values and help in arriving at the exact SHR values Stacking loss as suggested by~~ CEA has also recommended consideration of stacking loss~~may~~

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		Received" and "As Fired" in the generating stations. c) Standardize GCV computation method on "As Received' and "Air-Dry basis" for procurement of coal both from domestic and international suppliers.	~~also be considered while considering GCV "As fired" for computation of landed cost.~~ ✓ CERC should clarify that the GCV for computation of fuel cost shall be ARB and not ADB in order to avoid ambiguity and conflicts between stakeholders.
33.	Fuel-Landed Cost 24.5	(a) All cost components of the landed fuel cost may be allowed as part of tariff. Or alternatively, specify the list of standard cost components may be specified; (b) The source of coal, distance (rail and road transportation) and quality of coal may be fixed or specified for a minimum period, so that the distribution company will have reasonable predictability over variation of the energy charges.	✓ Existing approach of considering actual fuel cost may be allowed ✓ The source of coal, distance and quality of coal depends upon the coal Supply Agreements executed by Generator. In case long term fuel supply agreement is not there, it would be difficult to specify this for a longer period. Hence, not possible
34.	Operational Norms 26	-	✓ Operation norms (for SHR, Auxiliary Consumption, SFOC etc) depend upon various design considerations. Suitable buffer is provided to factor in departure of actual site conditions as compared to design parameters. Norms so fixed act as ceiling norms. Therefore, the norms once fixed cannot be reduced based on actual performance. ✓ Current regulations do not provide for degradation in operational parameters on account of ageing. It is proposed that a suitable margin be added in the norms to capture the same
~~34.~~35.	Operational Norms (SHR) 26.3.1 to 26.3.6	Thermal Generation (Coal based) Station Heat Rate 26.3.1 Station Heat rate (SHR) refers to the conversion efficiency of thermal heat energy into electrical energy and used for computation of energy charges. The Commission while framing the Regulations for terms and conditions of tariff for different tariff periods has been considering the operational data of the generating stations for the past 5 years. The methodology of considering 5 years data ensures that the generator is able to recover the cost of electricity	✓ Heat Rate is a design parameter. Margin provided over such design HR depends upon variance in actual site conditions as compared to parameters considered while designing the machine. Once the margin is fixed for any machine based on COD, the same cannot vary. Therefore, Margin needs to be fixed based on COD and to be continued for entire useful life. ✓ For machine having COD between 01.04.2009 to 31.03.2014, margin considered in Tariff Regulation 2009-14 was 6.5%. The same was reduced to 4.5% in Tariff Regulations, 2014. In view of above, it is suggested to restore 6.5% margin over guaranteed Heat Rate ✓ In fact, there is a need to factor in degradation in Heat Rate due to

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		in a reasonable manner and covers the reduction in the generation level.	vintage/ wear & tear of the machine year over year. Suitable margin may be added in the heat rate. ✓ Also, such SHR being the ceiling norms, only actual SHR is considered in case the same is lower than normative SHR. ✓ ~~Therefore, Margin of 4.5% needs to be continued over designed HR for future period.~~
~~35.~~36.	Operational Norms (SFOC) 26.3.7	With contribution from renewable generation increasing in the grid, thermal power plants are facing frequent regulations of supply and operations at lower PLF up to technical minimum. The consumption of secondary fuel oil would change on account of nature of operations.	✓ The norms of 0.5 ml/kwh does not capture the consumption of fuel related to frequent start-stop or higher oil consumption at low PLF. IEGC provides for compensation of start-stop only after 7 operations. Therefore, SFOC norms may be increased to ~~2~~ 1 ml/ kwh in order to take care of frequent switching operations and running at technical minimum.
~~36.~~37.	Operational Norms (AEC) 26.3.7	-	✓ Normative AEC for any plant needs to be linked with COD of machine and once, it is fixed, there should not be any revision in such ceiling norms. ✓ Saving in AEC needs to be shared with predominantly higher benefit to the developer in order to create more impetus. ✓ Additional AEC and SHR may be considered for implementation of Env. Norm. ✓ Operational norms do not capture impact of RSD. During RSD, Several auxiliaries would be running for equipment / system protection. Cooling water system of the Main TG Condenser, Lubricating Oil system of the Main Turbine, Turbine seal oil system, Turbine BFP, Lube oil system of Mills, Compressed air system, Control & Instrumentation system, HVAC system, Lighting system, Furnace Scanner Cooling air system etc. would be in service during RSD resulting into higher Aux. Consumption. Such time bound increase in Aux. consumption cannot be made up on cumulative basis since the norms consider normal operation and not RSD. Hence, suitable compensation need to be provided for the same. ✓ Impact of Ageing may be considered additionally over current norms.

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			✓ The norm for 800 MW can be fixed based on analysis of actual auxiliary consumption for some 800 MW units operated under different conditions.
~~37.~~38.	Operational Norms (Normative Annual Plant Availability) 26.3.15	The existing norms of annual plant availability may need review by considering fuel availability, procurement of coal from alternative source, other than designated fuel supply agreement, shifting of fixed cost recovery from annual cumulative availability basis to a lower periodicity, such as monthly or quarterly or half yearly	✓ Consideration of annual plant availability as a basis for fixed charge recovery is mainly considering the fact that generator requires continuous planned outages for no. of days for COH/ AOH and ~~it~~ if availability is to be considered monthly or quarterly, it will result in reduction of availability in such months. Moreover prior permission of Discoms is taken before COH/AOH. Further, Forced outages due to equipment failures, water availability, Seasonal disturbances are unpredictable. ✓ Above factors reduce availability considerably and if the periodicity is reduced to monthly or quarterly or half yearly, it will result in severe cashflow issues for Generators. ~~✓~~ Therefore, ~~frequency~~ Periodicity for availability cannot be reduced to any lower period than a year. ✓ In fact, concerns related fuel availability has made it difficult to achieve annual PAF stipulated at present. Therefore, level of 85% may be reduced to 65% for the purpose of recovery of fixed cost
~~38.~~39.	Operational Norms (Transmission Availability Factor) 26.5.1	26.5.1 Availability of Transmission System/ elements is expected to increase with introduction of new technology like polymer insulators etc. Thus, the mechanism of payment of transmission tariff based on availability of transmission system may need review.	✓ 26.5.1 CERC has already fixed stretched norms for Transmission availability of AC system. Therefore, there is no scope of any further reduction. Introduction of polymer insulator would only help in maintaining the availability at current level. Further it is to be noted that Polymer insulators are not installed in all operational lines and even stability and reliability of silicon rubber insulator is not established. It is also observed that polymer insulators are also failed in a span of 7 to 8 year life cycle. Hence, cannot be considered rational for increase of availability.
~~39.~~40.	26.5.5	Review of the incentive formula for HVDC bi-pole and HVDC back-to-back stations at par with AC system;	✓ Incentive formula for HVDC system should not be at par with AC system for following reasons: 1. Since, line length of HVDC system is more than AC system (3 to 4 times length AC line) and also line covers various region/

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			terrain/ weather conditions, cannot be comparable with AC system. 2. HVDC is state of art technology which involves complex controls and logic function and cannot be compared with AC system. 3. In HVDC system, both terminal stations along with line is considered as a one element. Hence, should not be equivalent to AC system. 4. Specialised technology (valve hall, pole control and station control) involved during maintenance activities which required longer outage period.
~~40.~~41.	26.5.5	d) Review of the existing methodology or procedure for computation of availability, monthly availability and cumulative availability;"	✓ The incentive & tariff calculations need to be consolidated annually, and the final settlement to be done on annual availability. ✓ At the present, it is very difficult to get RoW for maintenance of transmission line and hence hampering the regular maintenance activities. Therefore, present provision of loading of 12 hrs non-availability after second tripping needs to be revised to allow at least 4 tripping on annual basis, besides working out availability on Annual basis.
42.	Incentive 27.1	27.1 For generation, the incentive prior to 2009 was linked to normative PLF and 25 paise/kWh was paid for generation beyond normative PLF in case of thermal generating station. The incentive, in case of hydro generating station, prior to 2009 was linked to the capacity charges and capacity-index. The incentive during tariff period 2009-14 was linked to normative availability and generation beyond normative availability was payable at the fixed charge rate for the stations which are more than 10 years old or at 50% of the fixed charge for the stations up to 10 years old. In case of hydro generating stations incentive was linked to the capacity charges (50% of annual fixed charges) and normative availability. During the Tariff Period 2014-19, incentive for coal based generating plant was again linked to normative PLF of 85% @ 50	✓ Incentive represents the efficiency of the Generator and ought to be captured prudently. ✓ Current Regulation to provide incentive based on PLF is not correct, since it is not in the control of the generator and is based on the schedule decided by the Discoms. Therefore, Incentive shall be linked to availability

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		paise. 27.2 At present there is same incentive for availability during peak and off peak period. There may be a need for introducing differential incentive during peak and off peak periods.	
~~41.~~43.	Incentive 27.3	As regards transmission system, incentive is being recovered only through monthly formula of billing and collection of transmission charges. In the absence of clear provision regarding reconciliation of annual transmission charges and incentive with monthly billing, the concept of NATAF specified by the Commission in Tariff Regulations, 2014 requires review.	✓ There is no logic in specifying the recovery of incentive for transmission lines on a monthly basis, as the lines are taken out for maintenance, only for some time in a year and not on monthly basis. Therefore, it should be made applicable on an annual basis, as is done for the generation assets. Further normative availability is specified on Annual Basis and hence incentive should be calculated based on Annual cumulative availability, however, incentive should be paid on monthly basis.
~~42.~~44.	Implementation of Operational Norms 28	28.1 The tariff regulations … keep charging the tariff based on previous tariff order including operational norms. The operational norms notified by the Commission in new tariff regulations take effect much after the date of coming into force of new tariff regulations. Consequently, the benefits of the improved operational norms are passed to beneficiaries only after time lag of few months. Comments/ Suggestions 28.2 Comments and suggestions of stakeholders are invited whether the operational norms of the new tariff period should be implemented from the effective date of control period irrespective of issuance of the tariff order for new tariff period.	✓ Till the time operational norms are notified, there is no avenue of implementing the same. Therefore, retrospective implementation of the norms is not possible.
~~43.~~45.	Sharing of gains in case of Controllable	Sharing of gains in case of Controllable Parameters 29.1 The present regulatory framework provides for sharing of gains between generating company and beneficiaries in 60:40 ratio on account of improvement in controllable factors such as Station Heat Rate, Auxiliary consumptions, secondary fuel oil	✓ Any gain and loss due to variation from the normative parameters shall be to the account of developer. This will be the true reflection of the spirit of defining normative parameters and the Commission will also be saved from the task of scrutinising the accounts, year after year. ✓ At the time of fixation of existing norms, issue of lower PLF was not

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	Parameters 29	consumption, refinancing of loan and the true up of primary fuel cost. Subsequent to above, the compensation mechanism has been introduced for operation in CERC (Indian Electricity Grid Code) (Fourth Amendment) Regulations, 2016. The compensation mechanism aims to provide compensation if generating plant is operated at improved norms than ones specified in the amended IEGC Regulations of 2016. In view of the compensation mechanism, it needs to be considered as to whether the ratio of sharing of benefit may be reviewed. 29.2 The compensation mechanism introduced through IEGC entails the hedging of the risk of operating at low PLF. The compensation coupled with normative controllable parameters creates a buffer for generating companies. In view of this, the merit order operation can be linked with the PLF in such a way that the plants under Section 62 may be encouraged to compete for maximum PLF. 29.3 Further, different generators adopt different methodology for sharing of gain, say on monthly or annual basis. Thus, procedure for the monthly reconciliation or annual reconciliation mechanism may need to be prescribed.	in existence and therefore, not factored in the norms. Considering the same, due to emergence of low PLF situation, the Commission has provided compensation in degradation of operating parameters through IEGC. Therefore, the compensation under IEGC has no relevance with the ratio of sharing of gains. ✓ Even otherwise, if CERC is inclined to share the gains, the same may be predominantly higher for Generators/ Licensee so as to keep them motivated to achieve the higher efficiency. ✓ 29.2 – not understood ✓ Sharing of gains may be reconciled on annual basis
~~44.~~46	Late Payment Surcharge 30.1	The present regulatory framework provides for late payment surcharge at the rate of 1.50% per month for delay in payment beyond a period of 60 days from the date of billing. In view of the introduction of MCLR, the rate of late payment surcharge may need to be reviewed. One option is to add some premium over and above MCLR.	✓ LPS should act as deterrent for non-payment and hence, should be made more stringent. Accordingly LPS @ 1.5% per month may be retained ✓ It may also be noted that LPS is calculated on a simple interest basis while all the accounting is on compounded basis. Therefore, LPSC should be on higher side otherwise we will be incentivising the delays in payment. ✓ Payment appropriation norm needs to be specified in the regulation.

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			i.e. LPS followed by past dues followed by current dues.
~~45.~~47.	Non-Tariff income 31.1	31.1 The tariff determination under Section 62 of the Act follows the principle of cost of recovery which inter-alia provides the reimbursement of cost incurred by the generating company or the transmission licensee. The income on account of sale of fly ash, disposal of old assets, interest on advances and revenue derived from telecom business may be taken into account for reducing O&M expenses. Present regulatory framework does not account for other income for reduction of operation & maintenance expenses. However, in case of transmission licensee, the income earned from telecom business are adjusted in the billing separately. The principle of treatment of other income as applicable in case of transmission can be extended for the generation business.	✓ Presently, O&M Norms are fixed taking into account actual expenditure for past period. While doing so, revenue on account of disposal of old assets, interests of advances, revenue for telecom business etc. are already taken into account. ✓ Disposal of fly ash is new event and Generators are required to incur the additional expenditure for utilization of Ash which is not covered under O&M Expense at present. Therefore, there is no avenue for reducing the same from O&M Expense. In fact, recently, CERC has issued orders granting additional expenditure as pass through in terms of MoC notification after netting off the revenue if any. ✓ It is worth noting that as per the MoC Notification, Generator is required to maintain separate account for any revenue earned and need to utilize the same as provided therein. Therefore, it cannot be considered as Non-tariff income.
~~46.~~48.	Standardization of Billing Process 32.2	32.2 Some of the States are imposing electricity duty on the actual auxiliary consumption which may be higher or lower than the normative auxiliary consumption. Such electricity duty is passed on to the beneficiaries along with the monthly bill. Whether electricity duty is to be linked with actual auxiliary consumption or normative consumption or lower of the two, may need to be specified.	✓ Electricity Duty being uncontrollable factor, the same needs to considered as actual ✓ Linking Electricity Duty payment to normative Auxiliary Consumption will lead to double penalty to Generator. ✓ Auxiliary power consumption is the cost for generation for supplying power into the grid. Imposition of electricity duty on the auxiliary consumption is irrational. ✓ It is recommended that electricity duty shall not be linked with the auxiliary consumption and shall not be levied.
~~47.~~49.	Tariff mechanism for Pollution Control System (New		✓ CERC may introduce norms for recovery of Capital and Operational expenditure including additional Auxiliary consumption in consultation with CEA. ✓ The same norms may be made applicable to projects under 63 as well similar to the provisions made for low PLF in IEGC

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	norms for Thermal Power Plants) 33.		
~~48.~~50	Commercial Operation or Service Start date 35.3	Data telemetry, communication and restricted governing mode of operation are requirements of system operator to monitor real time grid operation and for grid stability. There is a need to ensure completion of data telemetry and communication by RLDCs/ NLDC/ SLDCs for declaring COD of transmission system/ generating station and operationalization of Restricted Governing mode of Operation (RGMO) in case of generating station.	✓ Transmission licensee does not have any control over RLDC /NLDC / SLDC and should not be made to suffer o account of any inefficiencies of RLDC / NLDC / SLDC.
~~49.~~51.	Commercial Operation or Service Start date 35.4	Delay can occur in the commercial operation due to factors beyond control or non-commissioning of associated transmission system. In case of the transmission system, the delay on account of non-commissioning of downstream or upstream system is more relevant. Since the declaration of commercial operation date attracts the liability of fixed charges or the transmission charges, as the case may be, the parties dispute the commercial operation date. In order to stream line the process of the declaring commercial operation date in case of the delay and to make aware the parties upfront about the consequences of delay, provisions could be made for demarcation of responsibilities or for Indemnification Agreement.	✓ The obligations of all the parties are well defined in TSAs and all commercial decisions should be in line with the provisions of TSA. Moreover, one person cannot be made to suffer on account of inefficiency of other persons, on whose action the first person does not have any control. In the past, there have been decisions wherein the defaulting parties have been asked to make payments beyond the provisions of TSAs, which is against the set doctrines of legal process.
~~50.~~52.	Alternative Approac	……	✓ As discussed earlier, it will not be appropriate earlier to change the tariff design approach at this stage considering the several issues, Generators are already struggling with.

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	h to Tariff Design (Normative Tariff by fixing AFC as a percentage of Capital Cost) 37.9		
~~51.~~53.	40	Merit order operation	✓ Currently SLDC's/TRANSCO's are backing down the renewable power despite of 'Must Run' status in the name of grid security without any compensation. Additionally generator may be forced to bear the additional cost of DSM charges during such unplanned back down, as there is little clarity about such scenarios in the regulations. ✓ Inclusion of renewable power in MoD will benefit the sector where in they will be compensated for the back down. Also since variable cost will be very low for renewables as compared to thermal power. Renewable power will not be back down or curtailed.